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AN ENGINEERING STUDY OF THE USE OF AIR AS A DRILLING FLUID IN THE APPALACHIAN AREA

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by

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FOREWORD

The cost of equipment, labor, and material necessary in drilling has been constantly and relentlessly increasing. Only the rapid technological improvements in drilling equipment and methods have maintained the stability of the oil well drilling cost. However, the necessity for searching deeper and deeper for oil will continue to increase exploration costs, even if the other costs of drilling were to remain constant. Therefore, new methods and techniques must be continuously developed to reduce or even stabilize drilling costs. This reduction in exploration and drilling costs is essential if the economic incentive to drill new wells is to be maintained.

The purpose of this thesis is to investigate the engineering aspects of air drilling in the Appalachian region, and to compare the resulting cost and production of wells drilled with air as the circulating medium with the cost and production of wells drilled in the same area using drilling muds. In addition an attempt will be made to determine the factors favoring or limiting the use of air as a drilling fluid, to predict the foreseeable uses of air as a circulating medium in the Appalachian area, and to recommend further application of the technique if the investigation should so indicate.

The author wishes to express his appreciation to Professor Holbrook G. Botset, Head of the Petroleum Engineering Department, University of Pittsburgh, for his helpful suggestions in the preparation of this thesis.

Acknowledgment is also made to Mr. H. J. Magner of the Delta Drilling Company for extending the use of their drilling data and for his generous assistance and co-operation.

I. INTRODUCTION

A. The Meaning of Air Drilling

Air drilling is a term which, through usage in the drilling industry, means the use of air or gas as the circulating medium on a standard rotary drilling rig. A more technical terminology in differentiating among the various circulating fluids used in rotary drilling is rotary-hydraulic and rotary-pneumatic drilling.[1] This distinguishes between the two extreme densities of drilling fluids, however, there are combinations of the two used (aerated muds) which do not completely fall into either category. Perhaps a more sensitive method of describing the circulating fluids now employed on the standard rotary drilling rig would be low density drilling fluids, and high density drilling fluids. The dividing line between the two would be water, with all circulating fluids with a density of water or greater being classified as high density fluids, and all those with a density less than water being classified as low density fluids.

In this paper, air drilling has been used to mean the utilization of air or gas as the circulating medium of a standard rotary drilling rig. The investigation and study covered only those rigs that were completely air or gas, or those that were completely mud. This eliminated all factors, elements, or functions of a drilling fluid whose circulating system contained a compressor and a mud pump simultaneously. In certain sections it was necessary to differentiate between air and gas drilling to present correctly the factors involved, particularly the fire hazards of using natural gas and the dangers of using air when drilling a natural gas formation.

[1] References are listed in the Bibliography.

B. History

The development of the science or the art of mud engineering is said to have been the most important single event in the past twenty years, so far as drilling technology is concerned.[2] The control of formation pressures and formation fluids is one of the more important functions of a drilling fluid. Since this function could be accomplished more positively and more readily by a weighted fluid, research and development were directed toward high density fluids. Low density fluids were initially used to control fluid loss and to obtain uncontaminated well completions. The use of low density drilling fluids for these functions highlighted other possibilities and their development began.

Experiments in the use of low density drilling fluid dates back to 1938 when several wells were completed using an aerated oil as the circulating medium.[3] In this operation a compressor was added to the usual circulating system and compressed gas was injected into the circulating oil system. The first large scale program to use air or gas as the only circulating medium was the completion of gas wells in the San Juan Basin of New Mexico operation of the El Paso Natural Gas Company in 1951.[4] The actual possibilities of air drilling did not come into prominence until fifty years after Spindletop.

Air drilling in the Appalachian region started in 1954, in an effort to drill wells more rapidly than was accomplished by the cable tool rig or the rotary rig using high density drilling fluids. The primary motivating force behind the desire for faster penetration rates was the lack of conservation laws in Pennsylvania. Since anyone with a plot of ground large enough to sink a well could do so and then produce the well as rapidly as

was technically possible, the producer with the most wells at the earliest part of the productive life of a field had the best opportunity for the most production and profit. The extravagance and waste of natural resources in the race to drill and exploit the Appalachian fields has been clearly indicated.[5] Perhaps the lack of conservation laws in Pennsylvania wasted millions of dollars in extra drilling and it probably caused the waste of millions of cubic feet of natural gas, but to its credit is the fact that it motivated the introduction of air drilling in the Appalachian area!

C. Characteristics of Air Drilling

Faster penetration rates, longer bit life, better control of lost circulation, fewer round trips, better operation in cold weather, cleaner cores, better detection of low pressure producing zones, and cleaner producing zones are the important characteristics that make air drilling desirable. Unfortunately, there are also undesirable characteristics. Air drilling cannot cope with all water bearing formations, it gives little support to sloughing formations, and it is of little assistance in controlling high pressure formations.[6] The inability of air drilling to handle all water bearing formations is the principle disadvantage encountered in the Appalachian area.

The most controversial characteristic of air drilling is the danger involved in its use. Some operators consider the use of air extremely hazardous to personnel, and allow only exhaust or inert gases to be used.[7,8] In other areas, such as the San Juan Basin in New Mexico, there is a sufficient quantity of cheap, high pressure natural gas to use as the drilling fluid. The primary advantage in using natural gas for well completions is the elimination of the elements necessary for a down-the-hole explosion. Laboratory tests, the reports of two underground explosions, and three underground fires support the theory that down-the-hole fires and explosions are not dangerous because of the relatively low pressures developed in systems open to the atmosphere.[8] When drilling with natural gas or penetrating a gas bearing zone, surface fires at the derrick floor are always a hazard, but ordinary precautions to eliminate gas leaks, flame or sparks at the rig make the operation safe. There have been a number of rig fires reported which resulted in the loss of the drilling rigs; all fires however were traced to carelessness on the part of the operating personnel.[9] In the reports of

the down-the-hole fires and explosions, only minor equipment damage was reported. None of the reports included any mention of injury to personnel. This would indicate that the procedures used in air drilling were safe. Several companies have reported drilling in the explosive range of from five to fifteen per cent methane in air, for as many as 15 to 20 days without an explosion.[10] Again, this would indicate the relative safety of the operation.

Another problem unique to air drilling is the dust arising from the discharge of cuttings. In unpopulated areas this presents no particular problem, however, in urban areas a cyclone settler or water filter of suitable design must be used to eliminate the dust.

D. Application of Air Drilling

1. Locations

Air drilling has been applied, in a limited manner, in almost every area where drilling is done. Specifically air drilling is known to have been done in Canada, California, Utah, Oregon, Wyoming, Colorado, New Mexico, Oklahoma, West, Central and Northeast Texas, Arkansas, Mississippi, Pennsylvania, Maryland, and West Virginia.[10]

2. Methods in Use

Figure 1 shows schematically the basic circulating system for air drilling. A compressor replaces the mud pump in the drilling mud circulating system. In addition a rotary blowout preventer is necessary to provide a seal around the annulus and around the drill string. This packer or seal diverts the air and cuttings into the conductor pipe leading to the disposal area. Variations of the basic system have been made to fit particular situations such as, the closed system using an inert gas which is filtered and recirculated, the exhaust gas system with the necessary equipment to cool and dehydrate the exhaust gases before circulation, and the use of natural gas. In addition, reverse circulation (from compressor to annulus, up the drill pipe to discharge) has been used, particularly for drying out the hole, for some fishing jobs, and to obtain larger cuttings for geological purposes.[10]

SCHEMATIC DIAGRAM
OF THE CIRCULATION
SYSTEM FOR AIR DRILLING

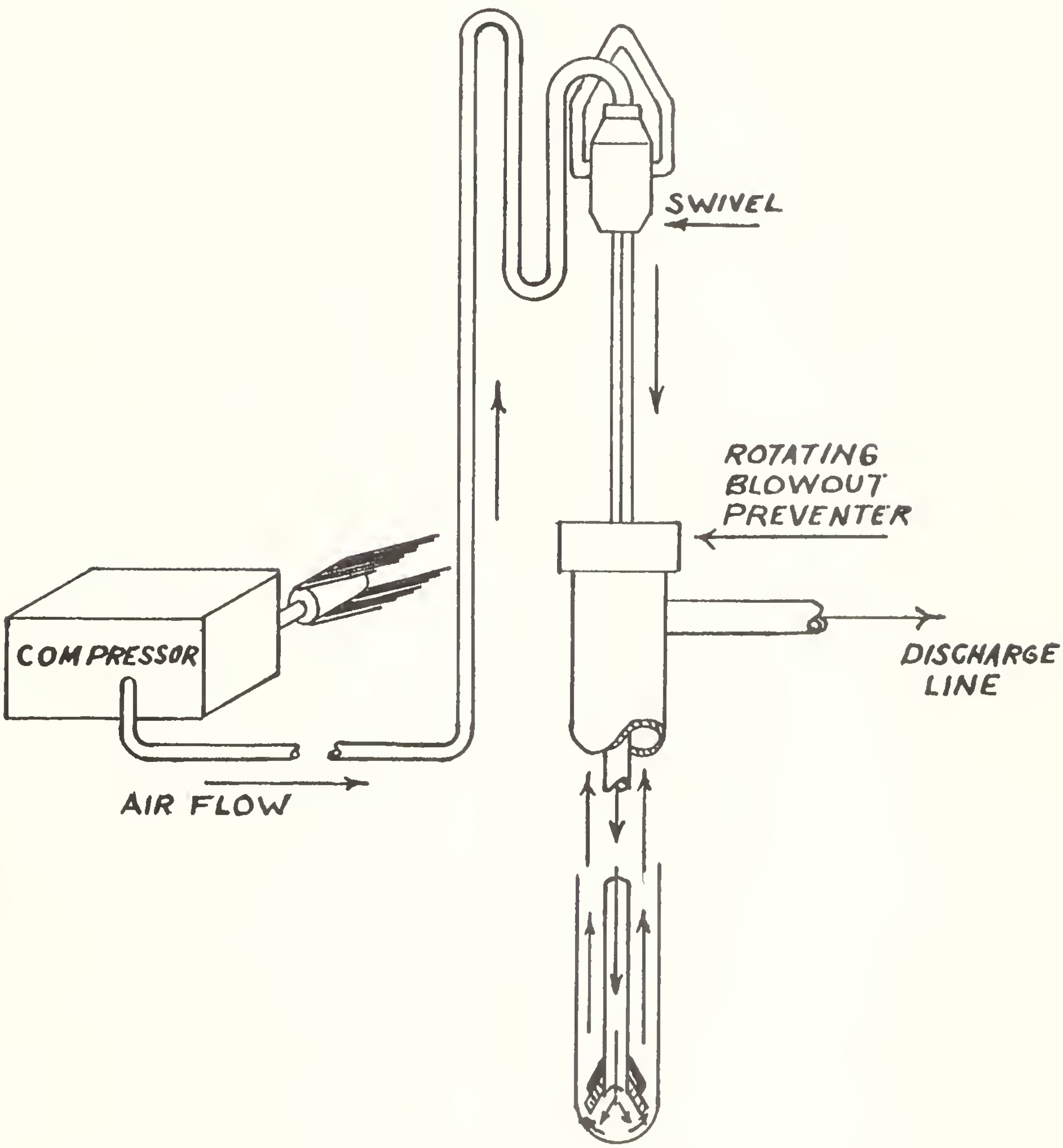

Figure 1

II. THE AVAILABILITY AND ADEQUACY OF AIR DRILLING DATA IN THE APPALACHIAN AREA

Since air drilling is relatively new in the Appalachian area, the available data for comparison and correlation with other types of drilling are rather scarce. In addition to the sparseness of data, there are other factors that had to be considered in evaluating the accuracy and usefulness of the information for comparative purposes. For instance, on some of the air drilled wells the first several hundred feet were spudded in with a cable tool rig, the surface and water strings of casing set, the cable tool rig moved off, and the remainder of the well air drilled. On many of the mud-drilled wells only the section below the water string of casing to the top of the production zone was rotary drilled.

The drilling data came from three operational rigs drilling on various locations over a two and one-half year period. The wells were in close proximity to one another and the geological formations penetrated were almost identical, but certainly all conditions could not be duplicated as is desirable for comparative work. Also the personal interest, ability, and experience of the operating personnel play an important part in the drilling time of a well. On one well drilled with mud, a mud engineer was retained to keep a constant check and control of the drilling mud properties. This was done in an effort to increase the penetration rate, and as could be expected, this well turned out to have the best drilling rate obtained with the use of mud.

To compare the open flow characteristics of the wells, data were obtained on the completion method of the wells and their open flow capacities.

The air drilling cost information from the contractor's operations was complete and itemized on a per rig basis, but not on a per well basis. This made the cost comparison of air drilling to mud drilling difficult because the rigs had engaged in air drilling exclusively or both air and mud drilling. Lacking the desired side by side operations with the resulting costs of the two methods, an estimated cost comparison was made on the basis of the contractor's field experience and knowledge. The complete information required in a cost comparison analysis was not available, however, the resulting per foot cost of the two methods was available.

III. FUNCTIONS OF AIR OR GAS IN AIR DRILLING OPERATIONS

A. Lifting and Removal of Cuttings

1. Air Drilling Dry Formations

In air drilling operations the air or gas replaces the functions of the drilling mud on a standard rotary rig. The lifting capacity of the air stream must be sufficient to remove the cuttings without excessive regrinding. One approach to the air requirements problem was to determine the velocity required to lift a pre-determined size cutting.[6] The drag force on the particle is dependent upon its shape, area, the density of the flowing air stream, and the square of the air stream velocity.[11] Expressed in a mathematical formula:

$$\text{Drag Force} = CA\,\frac{pU^2}{2}$$

where "C" is the drag coefficient, "A" is the projected area of the body on a plane normal to the flow, "p" is the density of the air stream, and "U" is the velocity of the air stream. The requirements are determined by equating the drag on the particle to the forces acting down on the particle. The downward force on the particle is gravitational force and is equal to:

$$\text{Gravitational Force} = \frac{\pi g D^3(\text{density of particle} - \text{density of fluid})}{6}$$

where "g" is the gravitational acceleration of 32.2 feet per second, per second, and "D" is the spherical diameter of the particle. The cuttings are not exact spheres, but their shapes are sufficiently close to make the assumption of sphere-shaped cuttings an acceptable approximation.[6] In the Appalachian area experience indicates that the optimum relation between penetration rate and horsepower requirements is obtained with a return velocity of air of 3000 feet per minute when drilling soft formations,

and 2000 feet per minute when drilling hard formations.[12] Faster return velocities did not result in an appreciable increase in penetration rates, but the higher return velocities did increase the continuous horsepower requirements. Slower return velocities decreased the penetration rates, finally reaching a return velocity that was too slow to remove the cuttings. Using the return velocity as the criterion, the volume of air necessary to obtain the desired return velocity is dependent upon the size of the hole and the size of the drill pipe. The horsepower necessary to deliver this volume of air is dependent upon the discharge pressure of the compressor. Figure 2, a composite of a chart and two graphs, was developed by the author to give a rapid graphic solution of air volume and power requirements with the only necessary information being bit and drill pipe size. The chart in Figure 2 is a tabulation of calculated annular areas for various combinations of standard bit and drill pipe sizes. The graph, annular area versus air volume, solves the calculations necessary to determine the volume of air required in obtaining the desired return velocity. The other graph, air volume versus horsepower, solves graphically the power requirements for the compressor delivering the required volume of air at the discharge pressure. Figure 3 is composed of part of the two graphs from Figure 2 on enlarged scales for air volume and annular area, and should be used with low values of annular area or air volume for more accurate results. Method of computation for the values in Figure 2 may be found in Appendix I-1. Friction loss was neglected in the computations, therefore, in wells deeper than one thousand feet some compensation for friction losses should be made. Experience data on friction losses in air drilling were not available. One authority on air drilling recommended the addition of twenty per cent to the volume requirements for every two thousand feet beyond a depth of two thousand feet.[13] To illustrate

the use of Figures 2 and 3, the conditions assumed are that a soft formation is being drilled with a bit 8 3/4 inches in diameter on a drill pipe four inches in diameter. The compressor discharge pressure is 50 psig. Entering the chart on Figure 2 with the bit and drill pipe diameters, an annular area of 47.56 square inches is obtained. Entering the graph on Figure 2 or 3 with the annular area of 47.56, extend the value horizontally until it intersects the 3000 feet per minute line, from the intersection drop a vertical line to the abscissa of the graph and read the air volume required. If drilling beyond a depth of 1000 feet, an increase in the volume requirement should be made at this point to compensate for friction losses. Entering the air volume versus horsepower graph with the required air volume, in this case approximately 1000 cfm at STP, extend the value vertically to the compressor discharge pressure line (50 psig), from this intersection extend a line horizontally to the ordinate and read the required horsepower value, approximately 113.

2. Air Drilling Water Bearing Formations

Of all the difficulties encountered in air drilling, the water bearing formations have posed the most onerous problem. Most drillers to date have "solved" the water problem by switching to high density muds, or in high fluid loss formations to aerated muds. Since the intent of this paper is to investigate and study certain aspects of air drilling only, possibilities other than complete air drilling were not considered.

There are two factors which limit the possibility of air-drilling wells all the way. They are water bearing formations and sloughing formations. In the Appalachian area these factors do not preclude the possibility of complete air drilling. For instance, there is an absence of water bearing formations below one thousand feet, which means that

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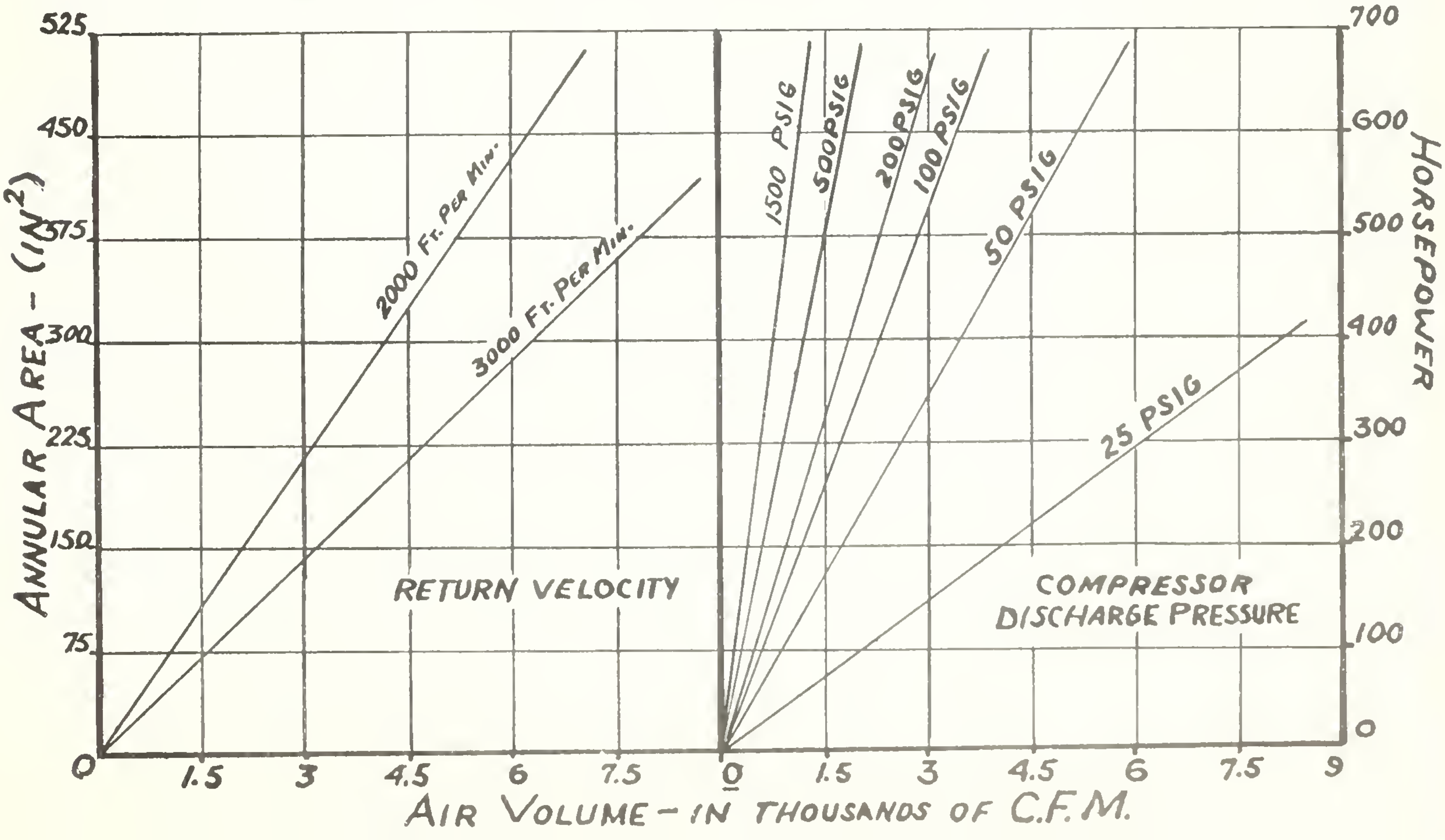
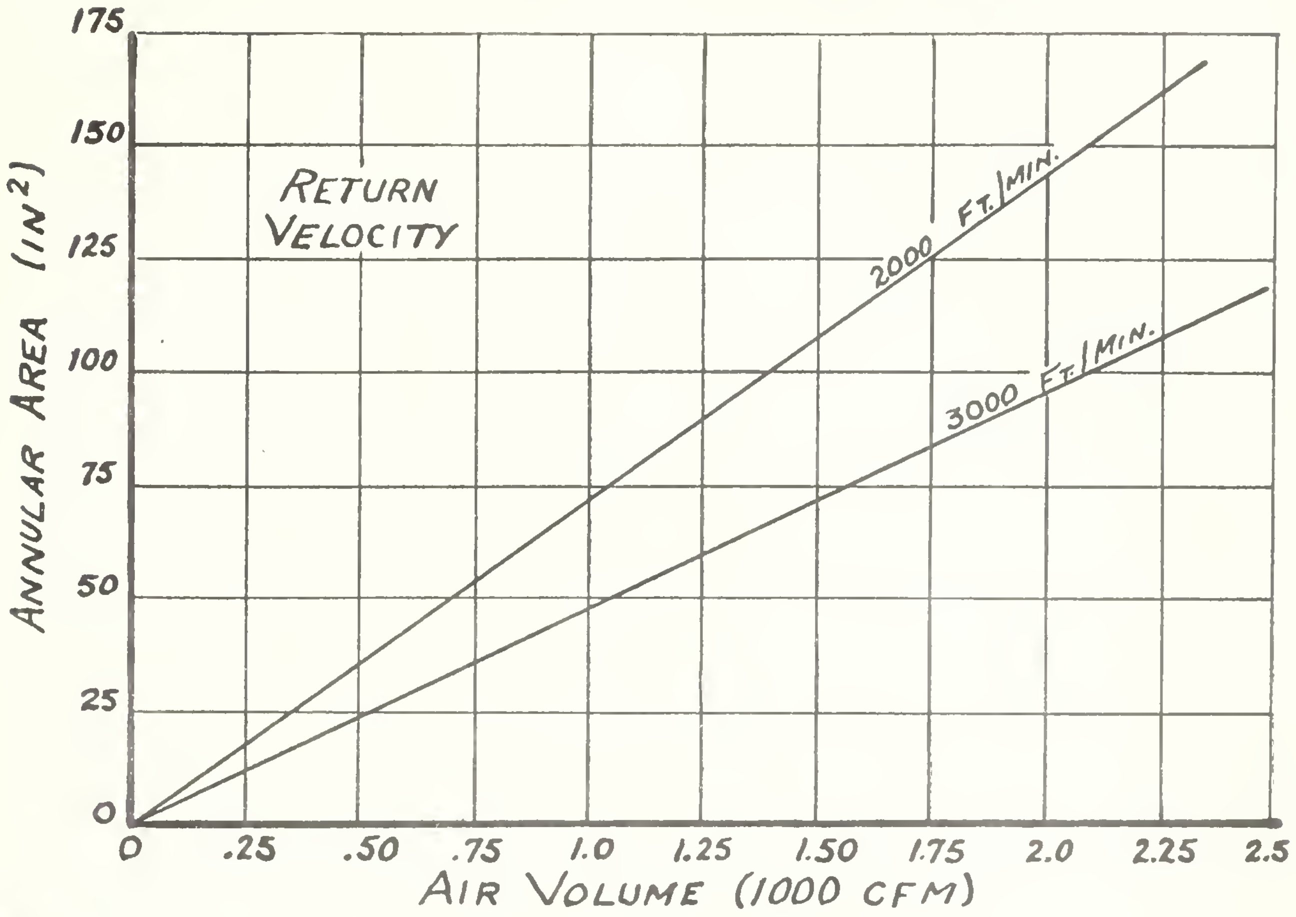
DRY HOLE AIR REQUIREMENTS
RETURN VELOCITY METHOD

BIT DIAM. (INCHES)	DRILL PIPE DIAMETER (IN)							
	$2\frac{3}{8}$"	$2\frac{7}{8}$"	$3\frac{1}{2}$"	4"	$4\frac{1}{2}$"	5"	$5\frac{1}{2}$"	$6\frac{5}{8}$"
3 3/4"	6.63	4.57						
3 7/8"	7.35	5.29						
4 1/4"	9.79	7.73						
4 5/8"	12.35	10.29	7.14					
4 3/4"	13.39	11.25	8.10					
5 3/8"	18.24	16.18	13.05	10.08	6.75			
6	23.86	21.80	18.65	15.70	12.37	8.64		
6 1/8"	25.01	22.95	19.80	16.85	13.52	9.79		
6 1/4"	26.27	24.21	21.06	18.11	14.78	11.05		
6 3/4"	31.37	29.31	26.16	23.21	19.88	16.15	12.02	
7 3/8"	38.25	36.19	33.04	30.09	26.76	23.03	18.90	8.24
7 5/8"	41.19	39.13	35.98	33.03	29.70	25.97	21.84	11.18
7 3/4"	42.76	40.70	37.55	34.60	31.27	27.54	23.41	12.75
7 7/8"	44.25	42.18	39.03	36.08	32.75	29.02	24.89	14.23
8 1/2"	52.34	50.28	47.13	44.18	40.85	37.12	32.99	23.33
8 5/8"	53.95	51.89	48.74	45.79	42.46	38.73	34.60	23.94
8 3/4"	55.72	53.66	50.51	47.56	44.23	40.50	36.37	25.71
9"	59.21	57.15	54.00	51.05	47.72	43.99	39.86	29.20
9 5/8"	68.27	66.21	63.06	60.11	56.78	53.05	48.92	38.26
9 7/8"	72.10	70.04	66.89	63.94	60.61	56.88	52.75	42.09
10 5/8"	83.84	81.78	78.63	75.68	72.35	68.62	64.49	53.83
11"	90.62	88.56	85.41	82.46	79.13	75.40	71.27	60.61
12"	108.69	106.63	103.48	100.53	97.20	93.47	89.34	78.68
12 1/4"	112.45	110.43	107.28	104.33	101.00	97.27	93.14	82.48
13 3/4"	143.04	140.98	137.83	134.88	131.55	127.82	123.69	113.03
15"	172.30	170.24	167.09	164.14	160.81	157.08	152.95	142.29
17 1/2"	236.12	234.06	230.91	227.96	224.63	220.90	216.77	206.11
22"	375.72	373.66	370.51	367.56	364.23	360.50	356.37	345.71
23"	411.07	409.01	405.86	402.91	399.58	395.85	391.72	381.06

ANNULAR AREA - (IN^2)
FOR VARIOUS SIZES OF BITS & DRILL PIPE



Expanded Scale Graphs from Figure 2 for More Accurate Readings with Low Values of Air Volume and Annular Area



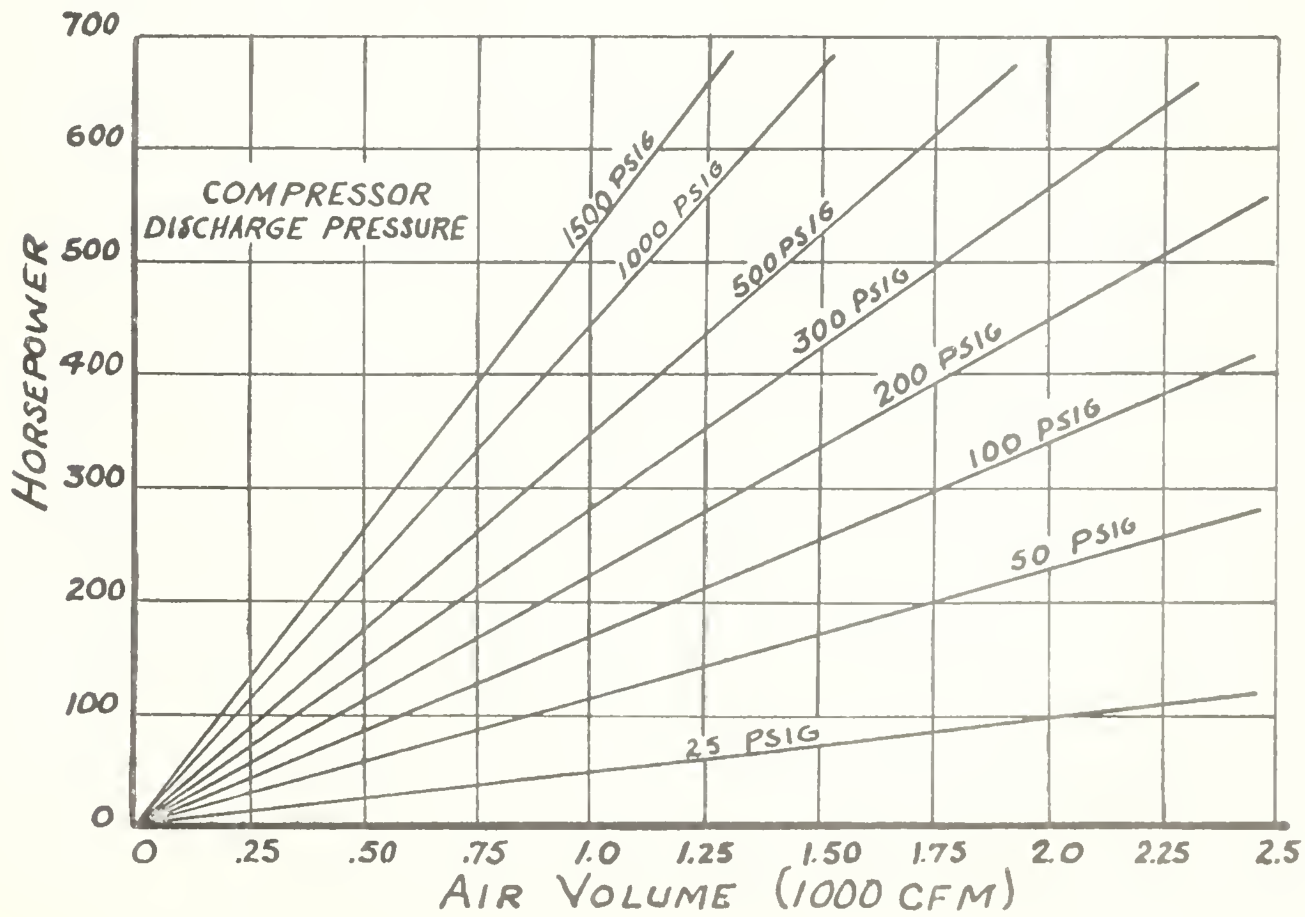


Figure 3

in the Appalachian area a 500 psig. compressor would be sufficient to blow out a hole 1,000 feet deep completely filled with water having a specific gravity of approximately one. The following example illustrates the limiting effect of water bearing formations when they are encountered at extreme depths. If while making a round trip from a depth of 7,000 feet the hole filled with 4,000 feet of water having a specific gravity of approximately 1.15, a minimum pressure of 2,000 psig would be required to unload the hole, or the time consuming method of unloading in stages would have to be used. Although this would not be an impossible pressure to obtain, it is certainly above the economical range, and a limiting factor to complete air drilling. Sloughing formations, the other limiting factor, are not encountered in the Appalachian area.

The author's approach to the water problem was to consider the hole with encroaching water as being analogous to a well producing by gas lift through the annulus. An investigation of possible sources of information on the pressure gradients and friction losses of wells producing through the annulus revealed little. One authority on gas lift techniques stated that information on annulus gradients and friction correlations was not available.[14]

The first step in determining the magnitude of power required to remove the water from the hole was to calculate the work necessary to lift a given quantity of water a specific number of feet. The weight of water was assumed to be 350 pounds per barrel. The weight of water multiplied by the height of the lift gave the minimum amount of work required to remove the water from the hole. To correct this minimum to a realistic value, the efficiency of the gas lift must be applied. This is extremely low, ranging from five to sixty per cent.[15,16] In developing the requirements, the lowest figure was chosen because:

(1) Submergence is a factor in gas lift efficiency, and the point of injection in air drilling has, in most cases, very little submergence.

(2) The large injection opening at the bit is inefficient, as it permits the formation of large bubbles which have more slippage than smaller bubbles.

(3) The large effective cross-sectional area in the annulus is conducive to slippage. In the Appalachian area the water bearing formations occur in the first one thousand feet of well depth where the annular area is the largest, and slippage the greatest.

(4) The listed ranges of efficiency were for cased wells being produced by pneumatic lift, therefore, the frictional resistance in an uncased hole would be much greater than in a cased well with production through a smooth conductor.

In developing the power requirements necessary to remove water from the hole, the author assumed that the efficiency of the lift was five per cent and that the specific gravity of the water encountered was one. With these assumptions the power required to remove the water from the hole varied directly as the quantity of water to lift and the height of the lift. By using log log paper with lift as the ordinate and water influx as the abscissa, the product of the coordinates of any point falling on a forty-five degree line was a constant, and therefore the power required for the combination of water influx and lift from any point on that forty-five degree line was also a constant. A series of forty-five degree lines was drawn with each line representing a specific power requirement. To project these power requirement lines to a scale, a single diagonal was drawn ninety degrees to the power requirement lines with the intersection of these lines projected vertically to the power scale. Figure 4, therefore, gives a graphic solution

IDEALIZED POWER REQUIREMENTS NEEDED TO REMOVE WATER FROM THE HOLE USING AIR. EFFICIENCY OF LIFT 5%

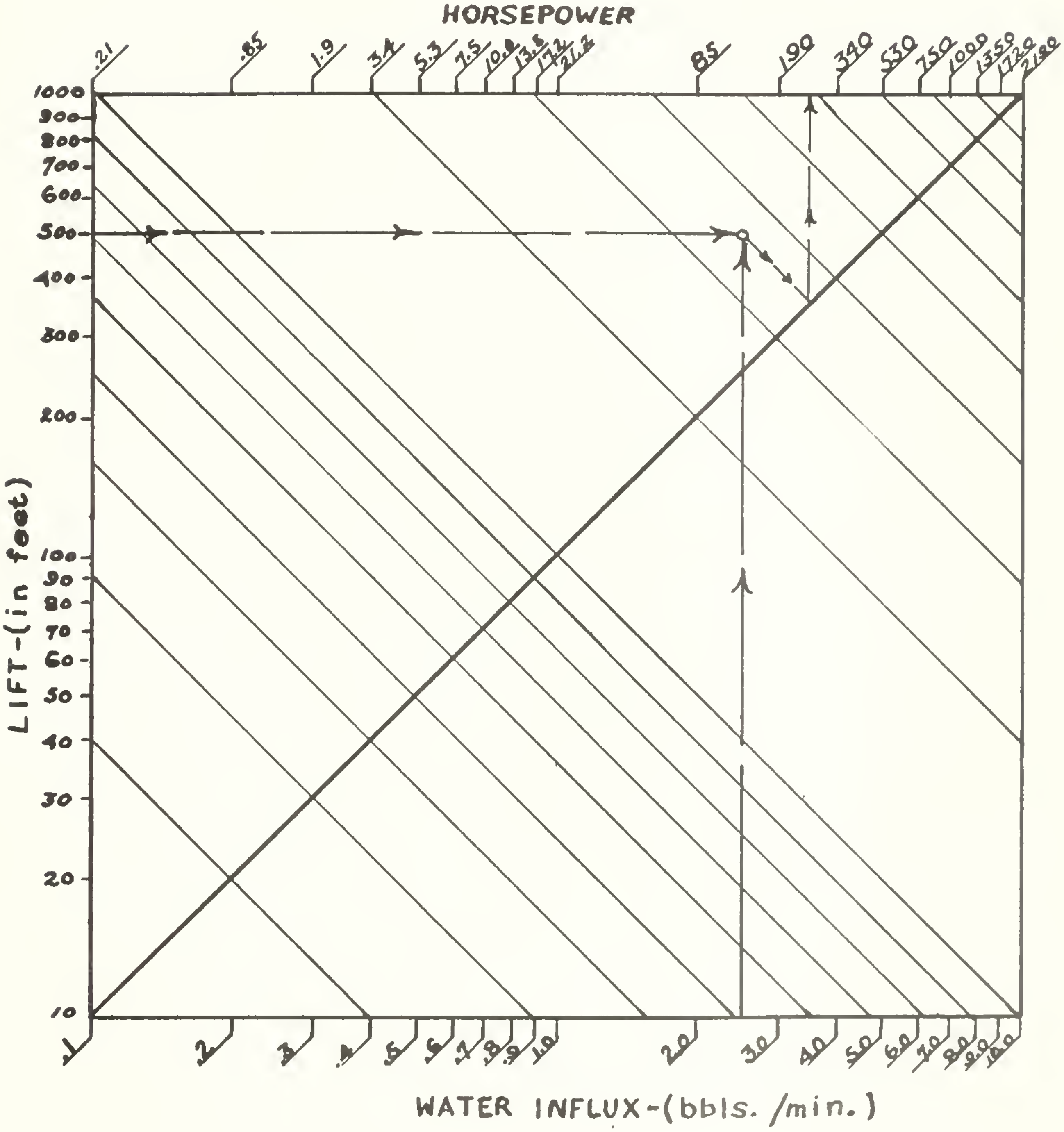


Figure 4

for the horsepower requirements for water removal at all the depths and rates of water influx encountered in the Appalachian area. Method of calculating values for Figure 4 may be found in Appendix I-2. To illustrate the procedure for determining the power requirements to remove water from the hole, the assumed depth is five hundred feet with an estimated water influx of 2.5 barrels per minute. Figure 4 indicates a requirement of 265 horsepower for these conditions. This value is found by extending the depth value horizontally from the ordinate and the water influx value vertically from the abscissa until they intersect. From the point of intersection project a line parallel with the forty-five degree lines until it intersects the single heavy diagonal. From this intersection project a line vertically to the horsepower scale and read the horsepower requirement, in this instance 265. The horsepower requirements obtained from Figure 4 may be converted to cubic feet of air per minute by using the air volume versus horsepower graphs developed for Figures 2 and 3. A representative of the Delta Drilling Company stated that one of this company's rigs drilled through a water bearing formation at 900 feet using approximately 2200 cubic feet of air per minute at a pressure of 150 psig. The air volume versus horsepower graph developed for Figure 2 indicates a usage of approximately 450 horsepower which was slightly under the amount available from the rig. Then from Figure 4 the water influx would be approximately 2.5 barrels per minute. This is not too far from what could be expected from the water bearing formations in this area. Unfortunately, the amount of water was not measured. The values obtained from Figure 4 are not meant to be a positive guide to the power requirements of all water problems. The values should only be used as a rule of thumb as certain factors would have to be modified for each case. For instance, in making up the chart the specific gravity of

the water was considered to be one. Obviously most of the water encountered will have a specific gravity greater than one and also it will be increased by the fine cuttings dispersed in the water. The power requirements, therefore, must be multiplied by the specific gravity of the water since the horsepower varies directly as the specific gravity. Also, the efficiency of the gas lift was considered to be constant throughout the range covered by the chart, however, as depth and quantity of water to be lifted change, the efficiency of the lift must also change.[17] Although Figure 4 is not an absolute solution, it does indicate the amount of power involved in removing the water by air lift, and indicates that most of the water problems encountered in the Appalachian area could be handled with available rig horsepower.

Reverse circulation, at first glance, appears to have possibilities for water removal. However, most of the advantages of air drilling are lost with the use of reverse circulation. Footage drilled per bit decreases drastically, lost circulation becomes a problem, and bits are more easily plugged when reverse circulation is used.[10]

When there is a likelihood of encountering water bearing formations, the driller must keep a constant watch for any signs of water in the cuttings. A little water in the cuttings causes the particles to become adhesive, but not wet enough to flow. The sticky particles build up on the drill pipe and well wall, restricting the flow of air and cuttings, finally building up enough to stick the drill pipe or to cause a twist off. In some instances the small water flows can be dried up by circulation of air without drilling. In other cases more water must be added through the air stream to increase the "flowing" quality of the cuttings until other water bearing formations are encountered or until the water zones are passed and cased off. The

graphic solution of power requirements for water removal, developed by the author for Figure 4, may also be used as a guide in determining the limiting quantity of water that may be added through the air stream and still keep the total quantity of water below the amount that can be handled with the available horsepower at the depth of drilling.

B. Lubricating and Cooling the Bit

Air is not considered a lubricant, consequently the bit receives no specific lubrication in air drilling. The absence of a liquid lubricant in air drilling is possibly one of the factors increasing bit life. The liquid lubricant besides lubricating the bit bearings, also holds grit and abrasives between the bearing surfaces causing the bit to wear out faster than the lubrication aids in extending bit life.

The circulating system in air drilling is analogous to a refrigeration system.[17] The drill pipe acts as the pressure chamber, the outlet at the bit acts as the throttling device with the annulus as the chamber slightly above atmospheric pressure. This throttling of the air and its expansion reduces the air temperature at the bottom of the hole and aids in cooling the bit. The temperature of the bit is further reduced by the great volume of relatively cool air passing through and around the bit. These cooling actions of the circulating medium in air drilling contribute to the extended bit life. A representative of the Delta Drilling Company in Pittsburgh, Pennsylvania, stated that they are presently testing a newly designed bit for air drilling. The bit is designed with air circulation around the bit bearings so that they receive more of the cooling effect from the circulating air. Initial results indicate the footage drilled per bit will be double that of a bit without air-cooled bearings under similar drilling conditions.

C. The Control of Formation Pressure and the Prevention of Formation Caving

Formation pressure cannot be as positively controlled in air drilling as it can with the use of drilling muds. In formations with low pressures, the lack of back pressure is an advantage, as the formations cannot be contaminated by the even lower pressure air passing through the annulus. In formations with extremely high pressures, the main difficulty arises when the drill pipe is being removed from the hole. The drill pipe must be securely snubbed at all times to prevent the high pressure from blowing the drill pipe from the hole like a projectile from an air gun.

In rotary drilling the circulating air causes less formation caving than circulating muds. This is clearly indicated by caliper logs which show that air-drilled wells are nearer true gage than mud-drilled wells. Air drilling cannot control caving or sloughing formations which are caused by factors other than the circulating fluid. When formation caving or sloughing has become so extensive that the maximum available air can no longer blow out the debris, then aerated muds and high density muds are the only solution at the present time. The addition of chemical sealers to the air is a possibility not yet developed for practical field use.

D. The Reduction of Casing Costs and the Minimizing of Corrosion

In comparing casing costs of air-drilled and mud-drilled wells in the Appalachian area, no significant differences were noted. Approximately the same surface, water and production strings of casing were set regardless of the method used in drilling the well.

Corrosion was an initial problem of air drilling, particularly when an exhaust gas was used. The use of corrosion inhibitors has completely eliminated this problem from air drilling.

IV. A COMPARISON OF CERTAIN PHYSICAL AND ECONOMIC ASPECTS OF AIR DRILLING TO THOSE OF MUD DRILLING

A. Physical Aspects

1. Penetration Rates

The most impressive facet of air drilling is the phenomenal penetration rates obtained. The drilling performance data listed in Appendix II show that the average penetration rate per well for air drilling over a two and one-half year period was thirty feet per hour while the average for mud drilling was 12.1 feet per hour. A comparison of the best penetration rates obtained shows an even greater gap. The best average rate per well obtained by air drilling was 48.83 feet per hour as compared to 17.15 feet per hour for mud drilling.

A laboratory experiment by the Hughes Tool Company has shown conclusively that reduction in hydrostatic pressure on a formation increased penetration rates.[18] This accounts for part of the increased drilling rate, but it cannot be credited as the sole factor in the difference between air and mud drilling. The air in air drilling results in less pressure on the formation being drilled, as compared to the resulting pressure caused by mud in identical circumstances, however, in the upper part of the well the pressures are not too far apart. For instance, the hydrostatic head at 200 feet would be approximately 100 pounds per square inch, which in many instances would be the same encountered in air drilling, yet air-drilling rates at this depth still far exceed those of mud drilling. Therefore, the pressure differential on the formation is only part of the answer.

In air-drilling shales in the Appalachian area, penetration rates have exceeded 100 feet per hour. These rates could be surpassed if sufficient

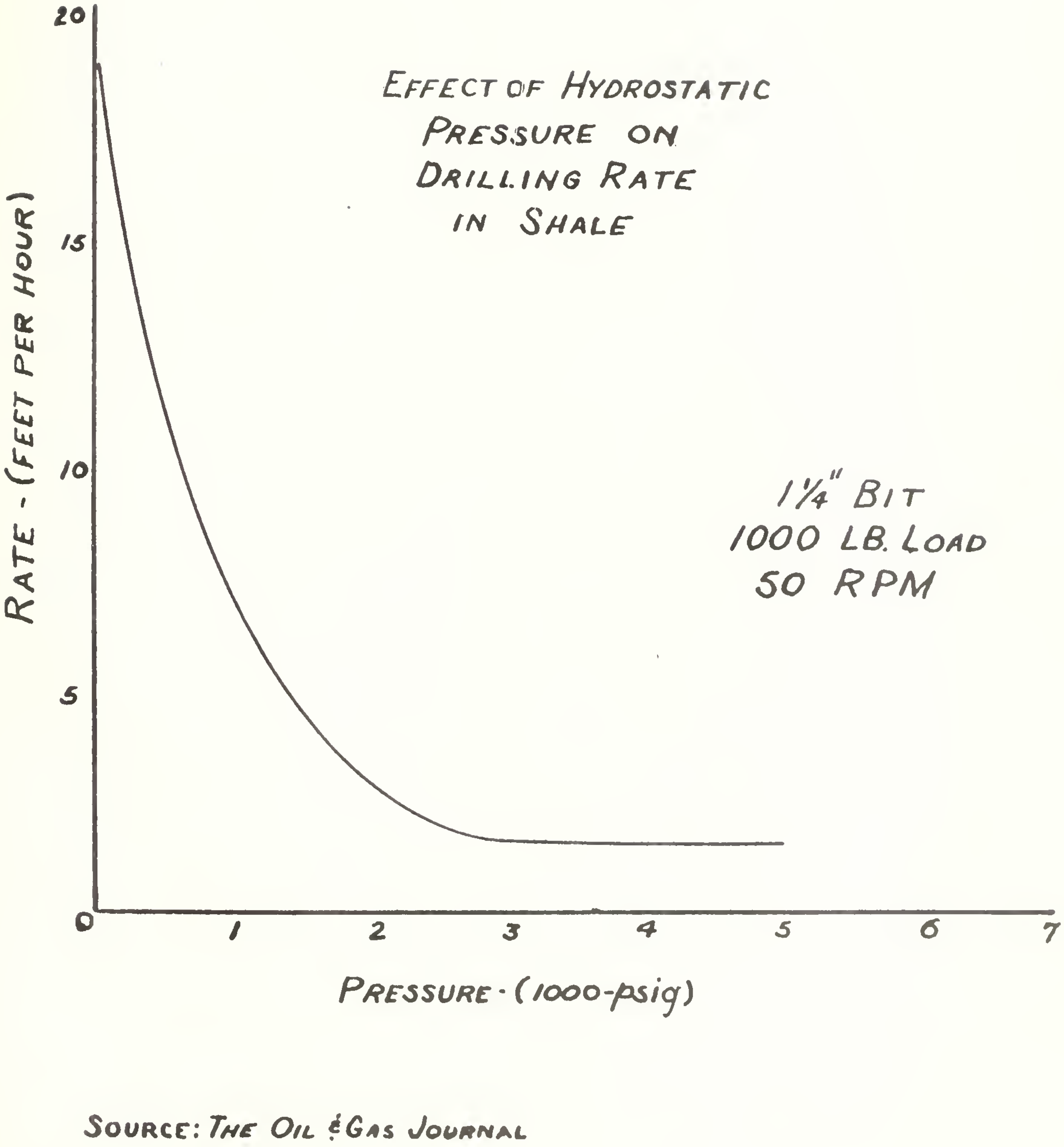

EFFECT OF HYDROSTATIC PRESSURE ON DRILLING RATE IN SHALE
1¼" BIT
1000 LB. LOAD
50 RPM
RATE - (FEET PER HOUR)
20
15
10
5
0
1
2
3
4
5
6
7
PRESSURE - (1000-psig)
SOURCE: THE OIL & GAS JOURNAL

Figure 5

air were available to remove the cuttings. What are the factors besides the reduction in hydrostatic pressures that affect the penetration rates? Speculations can be made, but positive evidence is not available. It is conjectured that mud tends to hold the cutting around the bit causing them to be reground over and over, while air drilling removes the cuttings from the bit immediately with only the exceptionally large cuttings being reground. Another contributing factor is that there are less cuttings to remove in air drilling than mud drilling, because air-drilled holes are more nearly in gage than the mud-drilled holes. Simply stated, the same size bit tends to drill a larger diameter hole when mud is used. Another difference, whether significant or not, is the fact that the long tooth bit gives the best penetration rates in shale when mud is used, but the short toothed bit gives the best performance when air us used. This indicates a necessity for research in bit design for air drilling. Another contributing factor is that the bit in air drilling is kept cleaner than is possible with mud drilling. Further experimentation and investigation should be made into the elements that increase the penetration rates because they may be applicable to other drilling operations or subject to further improvement in air drilling.

2. Bits Required

Contrary to expectations, the number of bits required in air drilling is less than the number required to drill a similar well with mud. In comparing the requirements the average number of bits per well was ten bits for air drilling and 35 for comparable mud drilling. The average footage per bit has steadily increased which has decreased the number of bits required per well. In 1954 the average number of bits per well was 19, in 1955 the average was 7 bits per well and the number has been further reduced in 1956

to an average of 5 bits per well. The best average footage per bit in a mud-drilled well was 234, while the best average footage per bit in a comparable air-drilled well was 1848. An interesting aspect in comparing the bit wear occurring in an air-drilled well and that in a mud-drilled well was the fact that the wear took place at different locations on the bit. In air drilling the bit was replaced because the shoulder containing the bearings for the rollers was considerably worn. The wear had progressed to such an extent that there would have been danger of losing a roller in the hole with continued use. On the bit used in mud-drilling a comparable well, the wear had taken place on the cutting surface making the cutting surface ineffective. When this is considered in the light that in air drilling the bit had drilled at least three times the footage of the comparative bit used in mud drilling, it becomes even more astounding.

Finding all the causes or factors influencing the extended bit life in air drilling as compared to mud drilling is even more difficult than determining all the elements involved in the faster penetration rates. A few contributing factors are known. For instance, the circulation of relatively cool air around the bit contributes to bit life. The absence of a liquid capable of holding grit, abrasives, and heat around the bit's working surfaces is another factor in increasing the footage per bit. Cleaner bits and less regrinding of cuttings are also factors involved in the increased footage per bit. The data conclusively show that air drilling increases the footage drilled per bit in comparison to mud drilling even though the bits were originally designed for mud drilling. The different locations of bit wear on bits used in air drilling as compared to bits used in comparable mud drilling indicates the need for further research in bit designs for air drilling and the likelihood of obtaining even greater footage per bit.

3. Well Completions

A cleaner method of completion necessitated the start of air drilling in the San Juan Basin of New Mexico in 1951, and is credited with making the production of the San Juan Basin economically feasible.[9] Although well completions in the Appalachian area were not the prime motivating force behind the introduction of air drilling, better completions were an important consideration. Several companies considered drilling into the pay zone with mud extremely detrimental to the production capacity, and required that all their wells be completed with cable tool. The Tennessee Producing Company of Houston, Texas drilled nine wells in the Appalachian area covered by this study and used mud all the way with no apparent damage to the producing sand.[19] A reservoir engineer for the company is of the opinion that there was no discernible difference between the capacities of the wells completed with a rotary rig using mud and those completed with cable tool, particularly since there was as much variation between individual cable tool wells as between mud-drilled and cable tool wells. However, in all other instances the customary procedure was to make all completions with cable tool until air drilling was introduced. Data were obtained on 45 wells in the Driftwood-Benezette Field from the New York State Natural Gas Company and are listed in Appendix III. Some of the wells were completed with cable tool and some by air drilling. Pressures and open flow capacities of the wells were checked to correlate any differences that were attributable to the method of completion. All the wells were in the same general vicinity, all were producing from the Oriskany sand and from the same reservoir. A study of the data indicated that no conclusive deductions could be made between production capacities of cable tool completed wells as compared to the production capacities of air-drilled wells. The data were so varied that by

selection the statistics could be arranged to show that air completions were superior or inferior to cable tool completions. For instance, adjacent wells drilled and completed within days of each other had completely divergent shut in pressures and open flow capacities. Unfortunately, there have been no subsequent shut-in pressure values with cumulative production figures to evaluate the production potentials of the wells. Perhaps these wells could all have been completed with mud drilling without damage to the producing sand. Again the geological characteristics of the Oriskany sand may be the determining factor in the production capacities of the wells. These are but a few of the questions that might have been answered if the proper production practices had been economically possible.

On investigation of the causes contributing to the wide variance of pressures and capacities of the wells, a geologist in the Production Department of the New York State Natural Gas Company, stated that he believed the highly faulted condition of the Oriskany sandstone in the Driftwood-Benezette gas field was the primary reason for the variation in pressures and open flow capacities of the adjacent wells. As the field became more completely drilled, this representative said that his company had attempted to determine the locations of wells for maximum production by interpreting pressures and open flow capacities of completed wells, as well as available subsurface geology, however, there was little consistency in their results. This indicated that the geological characteristics of the reservoir, such as the numerous faults, permeability, porosity, and sand thickness, were so varied that any attempt to correlate the reservoir pressure and open flow capacity would be so varied and inconsistent that it would be valueless.

Although the available data on well capacities in the Appalachian area do not prove conclusively that air drilling gives the cleanest and best

[illegible]

completions, it can be logically inferred that such is the case. In air drilling the absence of elements capable of contaminating the producing formation is a known fact. Air drilling is always safe, reservoir-wise, the other methods may or may not be.

One difficulty and hazard in completions unique to air drilling is the removal of the drill pipe from the hole after completion. Extreme care must be exercised to keep the drill pipe snubbed at all times. The pipe is removed with the well open and flowing, therefore, the expulsive forces are the drag of the flowing gas on the bit, joints, and pipe plus the force of any bottom-hole pressure acting on the cross-sectional area of the drill pipe. Experience indicates that the forces developed in a flowing well are not excessive in wells whose open flow capacity is under 150 million cubic feet per day. Figure 6 was constructed to illustrate the forces that could be encountered if the drill pipe were removed while the well was shut-in, and shows why shut-in completions should be avoided in air drilling. On the graph the expulsive force for various reservoir pressures was plotted against the length of pipe remaining in the hole. The expulsive force was calculated as the difference between the force, in pounds, caused by the reservoir pressure acting on the effective cross-sectional area of the drill pipe and the weight of the pipe remaining in the hole. Friction was neglected in the calculations, however the graph will give an indication of the forces that could be encountered when removing drill pipe from a completed air-drilled well if shut in. The method used to compute the values for Figure 6 may be found in Appendix I-3.

4. Crooked Holes

There have been conflicting opinions about the effect of air on hole deviation.[12,20] Laboratory and field tests on causes of crooked holes have

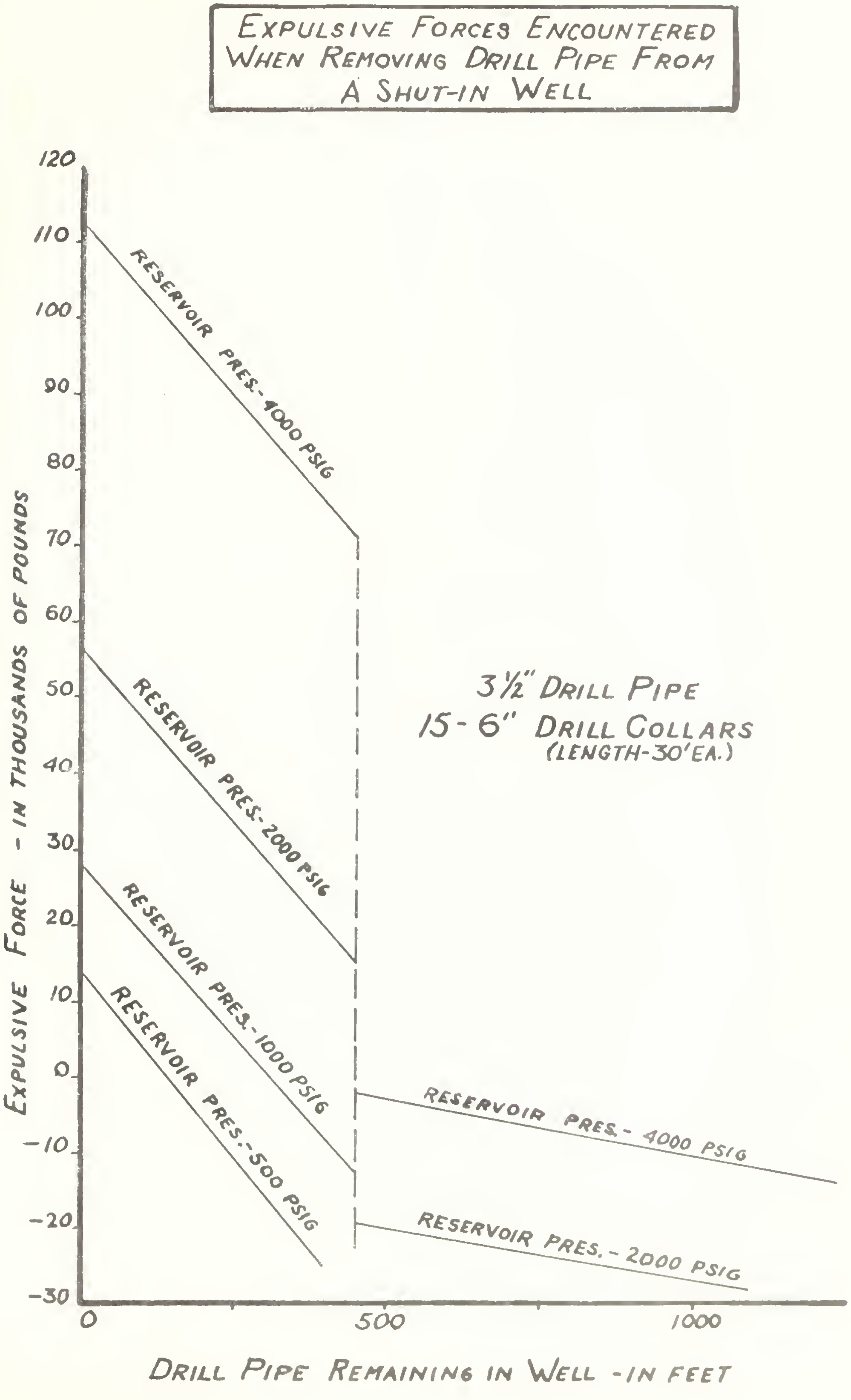

EXPULSIVE FORCES ENCOUNTERED WHEN REMOVING DRILL PIPE FROM A SHUT-IN WELL
EXPULSIVE FORCE - IN THOUSANDS OF POUNDS
120
110
100
90
80
70
60
50
40
30
20
10
0
-10
-20
-30
0
500
1000
DRILL PIPE REMAINING IN WELL - IN FEET
RESERVOIR PRES.-4000 PSIG
RESERVOIR PRES.-2000 PSIG
RESERVOIR PRES.-1000 PSIG
RESERVOIR PRES.-500 PSIG
RESERVOIR PRES.- 4000 PSIG
RESERVOIR PRES.- 2000 PSIG
3½" DRILL PIPE
15-6" DRILL COLLARS
(LENGTH-30' EA.)

Figure 6

indicated that the ratio of the diameter of the drill collars to the hole diameter, the weight on the bit, the hardness of the formation, and the formation dip are the main factors affecting the inclination of the hole and that the drilling fluid has little effect.[21] The same crooked hole corrective measures used in mud drilling such as less bit weight, faster rotary speed, and the use of two or four cone bits, work for air drilling also.[12] Tests for deviation must be made often because the faster penetration rates tend to make the deviation abrupt. It is the author's opinion that the faster penetration rates and the better gaged holes are factors of air drilling contributing to more abrupt deviation, but that the use of air as the drilling fluid is not a primary cause or influence in rotary hole deviation. To illustrate how faster penetration rates and better gaged holes affect hole deviation and increase the need for more frequent deviation tests, it is assumed that alternate layers of hard and soft formations with a dip are being drilled. In both air and mud drilling, the general tendency of the hole inclination is up-dip. As the bit drills the hard formation a slight up-dip deviation results in both types of drilling. In air drilling the penetration rate is relatively fast and the hole in gage. In mud drilling the penetration rate is slow and the hole enlarged. On drilling into the soft formation the in-gage hole holds the drill collars and the bit at the angle of inclination, while in mud drilling the larger hole allows the drill column to partially return to the vertical while drilling in the soft formation. As this process is repeated the abruptness in inclination becomes more apparent. Because of the abruptness and faster penetration rates, hole deviation must be checked more often.

5. Logging and Geological Information

Induction, gamma, neutron, caliper and temperature logs are successfully run in an air drilled well. In the Appalachian area few logs are run on wells regardless of the type of drilling, therefore, experience data for the wells investigated were not available.

Geological information from the cuttings is possible and the cuttings are not difficult to identify in most cases.[10] The cuttings reach the discharge pipe in a matter of seconds, eliminating the careful and intricate timing necessary in determining the exact depth of mud-drilled cuttings. Well logging and formation correlation is relatively non-existent in the Appalachian area. The employment of such techniques is more the exception than the rule.

B. Economic Aspects

1. General

The proof of technical progress in industry is the ability of a product or process to enhance the competitive position of the industry. An investigation of the competitive aspects of air versus mud drilling was made to determine the economic advantages, if any, of air drilling. Proof that air drilling in the Appalachian area was an economic success was immediately available. Contracting prices for drilling wells had been reduced from $9.00 per foot using mud to $6.00 per foot for a comparable well using air. A reduction of 33 1/3 per cent was certainly an economic improvement in drilling prices.

The average time lapsed for air drilling the wells was 200 hours drilling time with a total of 12 - 14 days on the hole, while mud drilling a comparable well averaged 475 hours drilling time with a total of 25 - 30 days on the hole. Air drilling has reduced the required productive and non-productive drilling time by 50 per cent. The over-all operational costs are higher for air drilling making the economic saving less than the actual time saving.

Figure 7 was made up from the operational cost of operating an air drilling rig one year. This does not represent any average, but is presented to show the cost distribution of air drilling wells and in what areas improvements would result in the largest savings. The first graph of Figure 7 is a breakdown of daily costs while the second graph is a breakdown of total costs and includes the daily costs.

2. Daily Drilling Costs

Daily drilling costs were broken down into labor, supervision, rig supplies, lubricants, drawworks repairs, pump repairs (mud only), engine

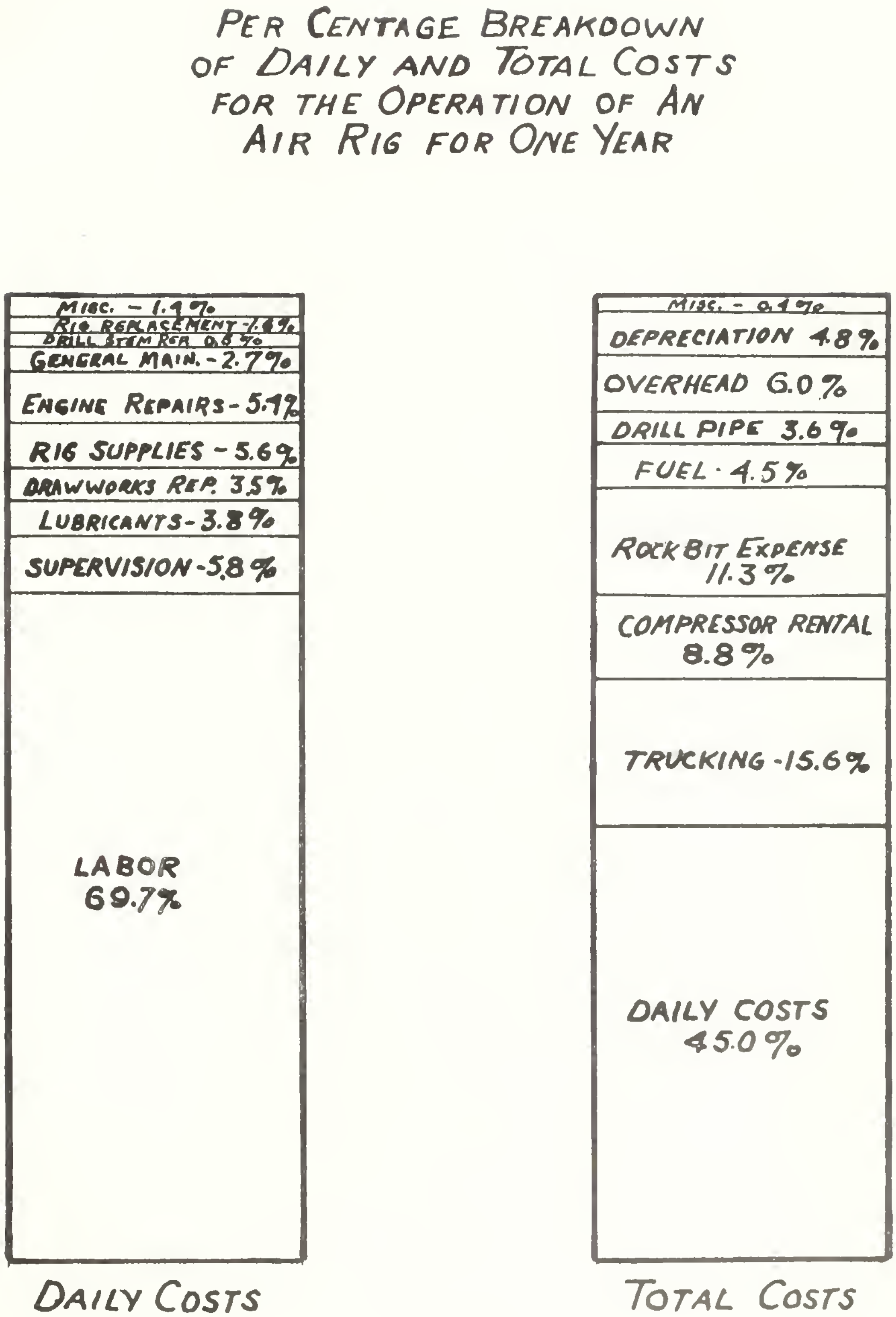

PER CENTAGE BREAKDOWN
OF DAILY AND TOTAL COSTS
FOR THE OPERATION OF AN
AIR RIG FOR ONE YEAR
MISC. - 1.9 %
RIG REPLACEMENT -1.8%
DRILL STEM REP. 0.8 %
GENERAL MAIN. - 2.7%
ENGINE REPAIRS - 5.9%
RIG SUPPLIES - 5.6%
DRAWWORKS REP. 3.5%
LUBRICANTS - 3.8%
SUPERVISION - 5.8%
LABOR
69.7%
DAILY COSTS
MISC. - 0.1 %
DEPRECIATION 4.8%
OVERHEAD 6.0 %
DRILL PIPE 3.6 %
FUEL - 4.5 %
ROCK BIT EXPENSE
11.3 %
COMPRESSOR RENTAL
8.8 %
TRUCKING - 15.6%
DAILY COSTS
45.0 %
TOTAL COSTS

Figure 7

repairs, drill stem repairs, general maintenance, rig replacement costs, and miscellaneous costs. Labor, supervision, and rig supplies were approximately the same daily cost for both air and mud drilling. Lubricants and drawworks repairs cost more for air drilling. Extra lubricants added little to the daily cost of air drilling, however, drawworks repairs were increased considerably. In air drilling the loads handled by the drawworks are more because of the unbuoyed drill pipe. Engine repairs in air drilling were more, particularly if the large stationary compressor was used and powered from the rig. Drill stem repairs are much less in air drilling because there is less abrasive wear caused by the air and cuttings than by mud and cuttings. General maintenance costs were approximately the same. Rig replacement costs were almost double for air drilling on a daily basis, however, on a per well basis the costs are identical. In air drilling the cable had to carry a greater load and be renewed more often, but there were fewer round trips required per well which made the costs on a per well basis the same for air or mud drilling.

3. Total Well Costs

In addition to the above daily rig costs which make up approximately 50 per cent of the total well costs, there are the variable well costs and the overhead-depreciation costs. The total well costs include daily costs, trucking, compressor rental (air drilling only), rock bit expense, fuel, drill pipe, overhead, depreciation and miscellaneous costs. Trucking costs are approximately the same for both methods. Compressor rentals are expensive and account for about 9 per cent of the total well costs. Rock bit expenses for air drilling are approximately one-fourth the amount required for mud drilling. Fuel for air drilling is slightly higher because the air compressors require a higher average horsepower output than the mud pump.

Drill pipe wear is much less in air drilling than in mud drilling. Field experience indicated that drill pipe is capable of twice the footage when used in air drilling, as compared to mud drilling. Overhead and depreciation are considered to be the same in both methods.

V. SUMMARY

The power requirement chart, Figure 4, developed by the author to determine the magnitude of power needed to remove water from the hole indicates that water bearing formations in the Appalachian area can be air drilled without excessive horsepower requirements. The investigation of air drilling in the Appalachian area indicated that the factors limiting air drilling are not prohibitive, and therefore drilling wells from top to bottom with air is feasible.

On a cost per foot basis air drilling was found to be 33 1/3 per cent cheaper than comparable mud drilling.

The variation in production capacities of wells completed using air compared to those completed using mud was inconclusive in the Appalachian area. Other areas have noted appreciable improvement in production capacities of wells completed with air as compared to either mud or cable tool completions.

The investigation indicated, in addition to the economic advantage, other factors favoring the use of air drilling. The most important factor is the time saved. This is extremely important in Pennsylvania where full capacity production is permissible on all wells. In addition, the certainty of clean completions and the simplicity of operating an air circulation system favored the use of air drilling.

The investigation indicated that the physical characteristics and the economic aspects of air drilling will stimulate, in the near future, the search for deeper producing horizons in the Appalachian area.

VI. CONCLUSIONS AND RECOMMENDATIONS

The investigation of air drilling in the Appalachian area has indicated that its capabilities far exceed those of other drilling methods. Geologically the area is ideally suited for the use of air drilling. The two factors, sloughing formations and water bearing formations, which generally limit the application of air drilling are not prohibitive here. Sloughing is not a characteristic of formations in this area. The water bearing formations have production capacities ranging from 0.4 barrel per minute to 8.7 barrels per minute and occur in the first thousand feet of depth.[23] Figure 4 indicates that the water situation can be handled without an excessive amount of horsepower except for the most extreme cases. Therefore, air-drilling can be used to drill wells from top to bottom without shifting to another type fluid. The penetration rates obtained in air drilling are phenomenal when compared to other types of drilling, however, the investigation indicated that improved bit design would increase these rates. Air drilling should make it profitable to penetrate deeper in the Appalachian area investigating the possibilities of lower producing zones. The air drilling rig is simple to operate and with strict adherence to ordinary safety precautions the hazards of air drilling are eliminated.

In conjunction with the operational characteristics, the economic aspects of air drilling are just as astounding. In a period of one year an air rig can drill twenty wells six thousand feet deep at a cost of $6.00 per foot. A similar rig using mud can drill ten comparable wells six thousand feet deep at a cost of $9.00 per foot. Therefore, similar rigs with almost identical investments and but little difference in operational costs, have gross annual incomes that vary from $720,000.00 for air drilling

to $540,000.00 for mud drilling. With moving to new locations involved a rig will not be on a hole continually, but the illustration points out the disparity that exists.

Air drilling in the Appalachian area has proved to be the fastest and most economical method of drilling. It can no longer be considered an experimental technique, on the contrary, it is quite capable of competing with the other methods of drilling. Cable tool drilling has the same contract price per foot as air drilling to a depth of 5,000 feet. Beyond that depth the cost of cable tool drilling goes up more rapidly than air drilling. In addition, the cable tool method is completely out of competition if time is an important element.

The momentary economic advantage now enjoyed by air drilling does not give the drilling industry any reason for complacency. Competition is not limited to the development of new techniques and the improvement of old methods within the drilling industry. The whole drilling industry is being challenged by the tremendous research and development efforts of the synthetic fuels industry. From 1945 to 1954 the drilling industry spent approximately $55,000.00 on research.[24] During the same period the oil industry and the United States Government spent over $10,000,000.00 in research and development of shale oil. The improvements of drilling techniques should not be left entirely to ingenuity and chance. If drilling and development costs of finding natural crude exceed the development costs of synthetic fuels, then the drilling industry will necessarily wane, for no operator can reasonably be expected to gamble on the possibility of obtaining natural crude when he can positively get synthetic crude at the same price.

It is recommended that the drilling industry sponsor, perhaps in cooperation with the operators, an extensive and intensive research and

development program to find new methods and to improve the old methods. In conjunction with this program, all problems that could effectively be done by Engineering Departments of Colleges and Universities should be assigned to them on a contract basis. This would not only accomplish the research, but would stimulate the interest of young engineers in petroleum production problems. It is further recommended that such a research program include the following projects for air drilling:

(1) A study of the expulsive forces on the drill column when completing a high pressure gas well and the best method of controlling these expulsive forces.

(2) A research program to determine the most suitable bit design for drilling water bearing formations and for drilling dry formations.

(3) A study of the friction losses encountered in the circulating system of air drilling with respect to depth and annular area.

(4) A research program to investigate the use of chemical mists for sealing water bearing formations.

(5) A research program to improve the efficiency of removing water from the hole.

(6) A research program to develop a method for continually recording pertinent geological information from the cuttings.

It is recommended that a program be initiated to instruct drillers in the importance and necessity for taking complete and accurate quantitative information in the field. Such information for air drilling should include the air volume being used for correlation with depth, type of formation being drilled, compressor discharge pressure, bit and drill pipe size, type of bit, and penetration rate; the quantity of water being removed from the hole when water bearing formations are encountered; and the pressure of the line

where the cuttings are discharged. Air drilling has great possibilities, but its true potential to the drilling industry will be realized only if the necessary field information is taken, analyzed, and used to initiate better techniques.

APPENDIX I

Calculations

1. Calculations for the air requirements in a dry hole using the return velocity method, Figure 2.

Annular area was determined by subtracting the cross-sectional area of the drill pipe from the cross-sectional area of the hole. For example, using a 8 3/4 inch bit on a 4 inch drill pipe the annular area would be:

$$A = \frac{\pi}{4}\left(\overline{8.75}^2 - \overline{4}^2\right) = 47.56 \text{ in.}^2$$

With the optimum return velocity assumed to be 3000 feet per minute, the quantity of air necessary to give the desired return velocity through the annular area is determined by multiplying the cross-sectional area of the annulus by the velocity. For example, using the above annular area the volume of air required is:

$$V = \frac{47.56 \times 3000}{144} = 990 \text{ cubic feet per minute STP}$$

Several points are determined and the results plotted on the graph of annular area versus cubic feet per minute.

To determine the horsepower required, the following formula was used:

$$HP = \frac{144}{33000} \times \frac{n}{n-1} \times p_1 V_1 \left[\left(\frac{p_2}{p_1}\right)^{\frac{n-1}{n}} - 1\right]$$

Where: n is the exponent that determines the type compression curve. The Mechanical Engineers Handbook states that under normal working conditions "n" is 1.3

p_1 is the initial pressure or inlet pressure in PSIA

p_2 is the outlet pressure from the compressor in PSIA

V_1 is the volume (cu ft.) of gas at p_1 compressed.

The horsepower requirements for the above example is:

$$HP = \frac{144}{33000} \times \frac{1.3}{1.3-1} \times 14.7 \times 990 \left[\left(\frac{64.7}{14.7}\right)^{\frac{1.3-1}{1.3}} -1\right] = 113$$

The results are then plotted for horsepower versus air volume for several compressor discharge pressures.

2. Calculations for determining power requirements for removing water from the hole, Figure 4.

The work required to lift one barrel of water is the weight of the water times the height of the lift. The weight of a barrel of water was assumed to be 350 pounds and the efficiency of the lift assumed to be five per cent. Therefore, the horsepower required to remove the water is dependent upon the height of the lift and the rate of water influx. For example, a water influx of one barrel per minute, at a depth of 100 feet would take the following horsepower for removal:

$$HP = \frac{350 \times 100 \times 1}{33{,}000 \times .05} = 21.2 \text{ HP}$$

The coordinates for the height of the lift and the water influx were plotted on log log paper and a forty-five degree (constant power requirement) line was drawn through the point. Where the forty-five degree line intersected the single diagonal, drawn at right angles to the power requirement lines, a line was projected from this point of intersection to the power scale. Other values were calculated and plotted for various depths and quantities of water encountered in the Appalachian area.

3. Calculations for determining the expulsive forces, Figure 6.

In determining the expulsive forces for this graph the drill pipe was assumed to be $3\frac{1}{2}$ inches in diameter with a weight of 13.3 pounds per foot connected with full hole tool joints, with fifteen - 30 foot drill

collars with a diameter of 6 inches weighing 90.7 pounds per foot. The reservoir pressure acts on the cross-sectional area of the drill pipe until the drill collar clears the hole at 450 feet. Then the reservoir pressure acts on the cross-sectional area of the drill collar. This force, expelling the pipe, is counteracted by the weight of the drill pipe and collars. Therefore, with 500 feet of drill pipe and collars in the hole the resultant forces would be:

Expelling:

Reservoir Pressure x Cross-sectional area of drill pipe

$$4000 \times 3.5 \times 3.5 \times \frac{\pi}{4} = 38{,}600 \text{ lbs.}$$

Downward:

Weight of pipe + weight of collars = 41,360 lbs.

Resultant force = 2,760 lbs. downward.

However, at 450 feet the expulsive force changes to:

$$4{,}000 \times 6 \times 6 \times \frac{\pi}{4} = 113{,}000 \text{ lbs.}$$

With a downward force:

Weight to collars = 40,700 lbs.

Resultant expulsive force = 72,300 lbs.

Similar resultant forces were calculated for other reservoir pressures and lengths of pipe in the hole and plotted in Figure 6.

APPENDIX II

Air-Drilled Wells in the Driftwood-Benezette Gas Field, Elk County, Pa.

Well No.	No. Bits Used	Total Footage Drilled	Drilling Time Hr.	Ft. Per Hour	Average Ft. Per Bit
388	20	5611	171	32.9	281
389	19	5301	161	33.0	279
391	26	5640	205	27.5	216
393	25	6354	201	31.5	254
396	14*	5475	192	27.7	391
398	9*	5543	206	26.9	616
Ross #1	7*	5553	202	27.5	793
432	12*	5945	236	25.2	495
433	9*	6077	229	26.5	675
384	33	6415	230	27.9	194
387	26	6336	204	31.0	244
390	28	6391	177	36.0	228
380	24	6093	189	32.2	254
Sch. #3	8*	4171	86	48.8	521
438	9*	5713	122	46.7	635
439	10*	6156	162	38.0	616
434	9*	6116	219	28.0	680
441	6*	5993	252	23.8	999
Musnlig	14*	7591	415	18.2	484
N398	4*	4004	101	39.8	1001
N444	9*	5770	203	28.5	641
N446	6*	5731	233	24.6	955
N450	4*	5802	224	25.9	1450
N451	6*	5672	213	26.7	945
N456	5*	5841	250	23.4	1168
N452	5*	4160	136	30.6	803
N466	5*	6528	189	28.0	1305
N476	5*	5479	178	30.9	1096
N478	3*	5545	163	34.0	1848
Hartzfeld #1	5*	6195	145	42.7	1239

*Indicates one or more "Cobra" or tungsten bits used in drilling the well.

ROTARY MUD DRILLED WELLS IN THE DRIFTWOOD-BENEZETTE GAS FIELD, ELK COUNTY, PA.

385	37	6304	486	13.9	169
349	37	6032	535	11.3	164
339	41	6079	594	10.0	145
365	43	6009	670	9.0	140
373**	31	6381	320	17.2	178

**Indicates the best results using mud.

APPENDIX II (Continued)

ROTARY MUD DRILLED WELLS IN THE DRIFTWOOD-BENEZETTE

GAS FIELD, ELK COUNTY, PA. (Continued)

Well No.	No. Bits Used	Total Footage Drilled	Drilling Time Hr.	Ft. Per Hour	Average Ft. Per Bit
363	32	5415	351	15.4	169
341	31	5036	587	8.1	162
355	35	5998	603	9.9	171
369	26	6084	532	11.4	234
374	39	5271	347	15.2	135
F. Knox #1	63	7700	861	7.9	123
H. Geo. #1	48	7029	805	8.7	146

APPENDIX III

Shut-in Pressures, Open Flow Capacities and Type Completion of Wells in the Driftwood-Benezette Gas Field, Elk County, Pa.

Well No.	Type Completion	Date	Orig. Open Flow MCF/day	Orig. Rock Pres. PSIG	Shut-in Time	Total Depth
337	Cable tool	9/9/53	4,332	3220	24 hrs	6947
338	Cable tool	11/25/53	4,642	3210	16 hrs	6965
339	Rotary-mud	11/6/53	4,992	3460	72 hrs	6977
340	Cable tool	8/10/53	2,117	3550	24 hrs	6871
341	Cable tool	10/29/53	14,854	3370	115 hrs	6913
347	Cable tool	12/11/53	17,196	3100	15 hrs	6965
348	Cable tool	1/23/54	9,811	2920	15 hrs	6893
349	Cable tool	1/11/54	412	3720	24 hrs	6491
355	Cable tool	11/6/53	14,671	3610	16 hrs	6900
358	Cable tool	5/17/54	3,916	3160	16 hrs	7019
359	Cable tool	6/11/54	1,400	2265	15 hrs	7111
360	Cable tool	9/15/54	996	1900	64 hrs	7007
361	Cable tool	5/27/54	850	2540	42 hrs	6944
362	Cable tool	10/12/54	3,373	1660	15 hrs	6950
363	Cable tool	4/17/54	7,810	3260	15 hrs	6381
365	Cable tool	2/7/54	3,523	2800	43 hrs	6940
369	Cable tool	2/4/54	4,845	3500	18 hrs	7007
370	Cable tool	5/19/54	4,950	2800	45 hrs	6892
371	Cable tool	6/9/54	18,762	3160	17 hrs	6809
373	Cable tool	3/3/54	40,284	3560	18 hrs	6414
374	Cable tool	4/3/54	4,895	3500	17 hrs	6201
376	Cable tool	9/18/54	1,018	1580	40 hrs	6315
379	Cable tool	7/2/54	920	2540	82 hrs	6373
380	Air	7/26/54	42,046	1910	14 hrs	7004
382	Cable tool	8/3/54	4,300	1575	24 hrs	6924
384	Cable tool	4/28/54	5,523	2980	60 hrs	7176
385	Cable tool	5/22/54	5,731	2556	40 hrs	7024
387	Air	6/2/54	3,474	2940	23 hrs	7080
388	Air	5/28/54	14,210	2960	18 hrs	6313
389	Air	6/21/54	4,452	2980	18 hrs	6224
391	Air	7/16/54	1,857	1620	-------	6366
393	Air	8/13/54	719	2600	136 hrs	7102
396	Air	8/24/54	5,731	1340	48 hrs	6303
397	Cable tool	3/11/55	696	1140	40 hrs	7225
399	Air	10/11/55	94	1410	64 hrs	6420
415	Cable tool	3/3/55	4,775	1120	41 hrs	7029
430	Cable tool	2/22/55	4,275	1465	15 hrs	6283
431	Cable tool	3/24/55	1,608	1260	17 hrs	6790
432	Air	12/29/54	4,332	3500	24 hrs	6884
433	Air	1/9/55	5,731	2725	20 hrs	7029
434	Air	5/10/55	894	2850	80 hrs	7076
438	Air	3/17/55	4,055	1125	21 hrs	6508
439	Air	4/7/55	869	2600	120 hrs	7105
441	Air	5/3/55	933	2750	116 hrs	6939
464	Air	9/26/55	778	3160	128 hrs	6975

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